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Economic feasibility of carbon sequestration with enhanced gas recovery (CSEGR)

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Abstract

Prior reservoir simulation and laboratory studies have suggested that injecting carbon dioxide into mature natural gas reservoirs for carbon sequestration with enhanced gas recovery (CSEGR) is technically feasible. Reservoir simulations show that the high density of carbon dioxide can be exploited to favor displacement of methane with limited gas mixing by injecting carbon dioxide in low regions of a reservoir while producing from higher regions in the reservoir. Economic sensitivity analysis of a prototypical CSEGR application at a large depleting gas field in California shows that the largest expense will be for carbon dioxide capture, purification, compression, and transport to the field. Other incremental costs for CSEGR include: (1) new or reconditioned wells for carbon dioxide injection, methane production, and monitoring; (2) carbon dioxide distribution within the field; and, (3) separation facilities to handle eventual carbon dioxide contamination of the methane. Economic feasibility is most sensitive to wellhead methane price, carbon dioxide supply costs, and the ratio of carbon dioxide injected to incremental methane produced. Our analysis suggests that CSEGR may be economically feasible at carbon dioxide supply costs of up to US$ 4–12/t (US$ 0.20–0.63/Mcf). Although this analysis is based on a particular gas field, the approach is general and can be applied to other gas fields. This economic analysis, along with reservoir simulation and laboratory studies that suggest the technical feasibility of CSEGR, demonstrates that CSEGR can be feasible and that a field pilot study of the process should be undertaken to test the concept further.
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1. Introduction

Carbon dioxide (CO_2) injection into oil reservoirs for enhanced oil recovery (EOR) has been a proven technical and economic success for more than 20 years. Although the advanced technology of injecting carbon dioxide (CO_2) into mature natural gas (methane, CH_4) reservoirs for carbon sequestration with enhanced gas recovery (CSEGR) appears promising, it has not yet been tried in the field nor shown to be commercially feasible. The process of CSEGR is depicted in Fig. 1 where we show the separation and compression of CO_2 from industrial and petroleum refining sources, injection into a mature natural gas reservoir, repressurization and enhanced production of CH_4, and the beneficial use of the CH_4 as a fuel. The mechanism of CSEGR is gas displacement and pressurization, as injected CO_2 moves through the pore space displacing CH_4 ahead of it [1]. This is in contrast to EOR which relies on miscibility of CO_2 with the oil phase, and enhanced recovery facilitated by the density and viscosity decrease of the oil-CO_2 mixture and corresponding greater mobility in the reservoir.

From the point of view of geologic carbon sequestration, depleted natural gas reservoirs are a promising target given their proven history of gas containment and production. The ultimate worldwide storage capacity of depleted natural gas reservoirs has been estimated at 800 Gt CO_2 (8×10^{14} kg CO_2) [2]. As for enhanced gas recovery, the average worldwide gas recovery factor is estimated to be approximately 75% [3], with roughly 30%–40% of the gas in place left behind in water-drive gas reservoirs and approximately 10%–20% left behind in depletion-drive reservoirs. Even 10% of the original gas in place in a depletion-drive reservoir can represent a large volume of currently unrecovered gas that makes potential incremental CH_4 production attract-

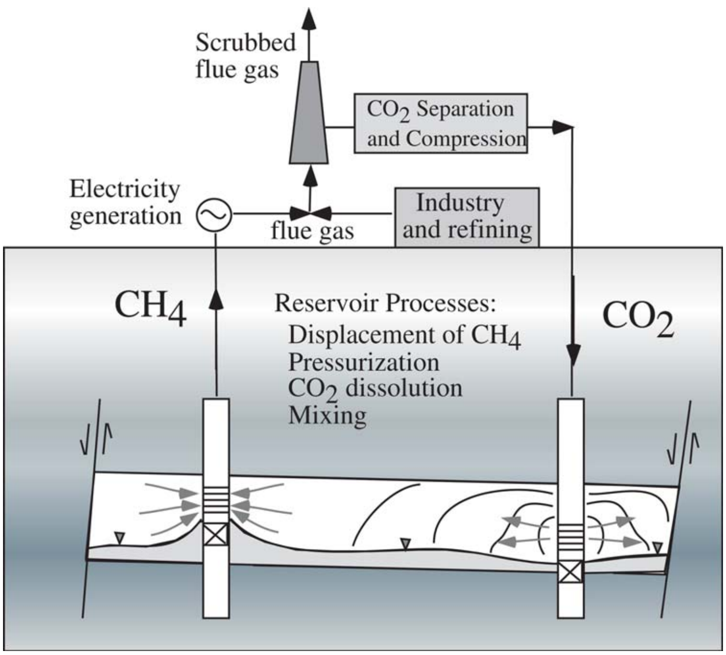

Fig. 1. Schematic of CSEGR processes.

ive when the alternative is field abandonment. In water-drive reservoirs where the potential additional CH_4 recovery potential is much higher, CO_2 injection will maintain reservoir pressure that will tend to keep water out of the reservoir. If CO_2 breakthrough to production wells occurs, separation of CO_2 from CH_4 can be carried out as a gas processing step with reinjection of the captured CO_2. Based on reservoir simulation and experimental studies, the process of CSEGR appears to be technically feasible. In particular, we have carried out numerical simulations of CO_2 injection into model natural gas reservoirs to study the processes of reservoir pressurization, gas displacement, and gas mixing [1,4]. Independent laboratory experiments of the displacement of CH_4 by supercritical CO_2 have further demonstrated the promise of CSEGR [5].

The purpose of this study is to investigate the economic feasibility of CSEGR. We selected the Rio Vista Gas Field in the Sacramento–San Joaquin Delta area of California (USA) for analysis. This gas field is typical of large onshore mature gas fields not associated with oil, and has the added feature of being near potentially large sources of CO_2 in the San Francisco Bay area. In our analysis, we first estimated the capital costs and operating costs for CO_2 acquisition and distribution, drilling or re-completing CO_2 injection and CH_4 production wells, gas purification and compression, and field design and monitoring. These costs are offset by the production of additional CH_4, the price of which will be variable depending on future market conditions. Although focused on a mature reservoir in California, the approach is general and can be used at other gas fields with appropriate changes in model variables. We focus our analysis on the present-day circumstances in which CO_2 must be bought from a supplier and is therefore a significant cost of CSEGR. Before presenting the economic analysis, we show reservoir simulation results of the physical process of CSEGR for the Rio Vista scenario being considered.

2. Reservoir simulation

A simplified numerical model based on the Rio Vista system [6] was developed for demonstrating the physical process of CSEGR. The reservoir is assumed to consist of 25 CO_2 injection wells, 16 CH_4 production wells, and eight monitoring wells placed over the central part of 16 km long by 7 km wide Rio Vista gas field. The well pattern and quarter five spot domain for simulation are shown schematically in Fig. 2. Injection and production are assumed to be in the Domengine sandstone, the largest gas pool at Rio Vista. Note in Fig. 2b that the CSEGR strategy we demonstrate involves injection of CO_2 into the lower regions of the thick reservoir while producing CH_4 from the upper regions. Injection of CO_2 is at a constant rate of 2.4 million t/year over the whole field, and uniformly distributed between the 25 injection wells (260 t/day per well). For comparison, this rate is approximately 57% of the CO_2 production rate of the nearby 680 MW gas-fired powerplant at Antioch, California. The simulation incorporates a total CH_4 production rate fixed at 750 t/day (15 MMMcf/year), or 48 t/day per well. This high production rate is nearly equal to the peak Rio Vista production in the 1940s, and was chosen simply to demonstrate CSEGR with a significant enhancement in production over the current Rio Vista production which is approximately 10^7 Mcf/year. Current production at Rio Vista represents the flattening tail of a production curve that declined by nearly one half from 1950 to 1960, and declined by over half again from 1960 to 1990. The idealized scenario

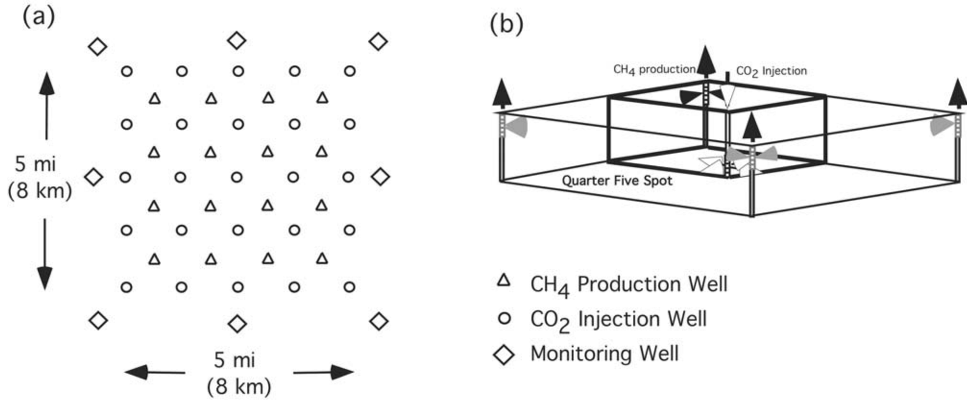

Fig. 2. (a) Schematic of well pattern for CSEGR with well spacing of 1 mile (1.61 km). (b) Perspective view of quarter five-spot simulation domain.

simulated here allows approximately seven times more gas to be produced from the reservoir over 15 years than the current production projected over this same period [1]. Other properties of the model reservoir are presented in Table 1. Simulations are carried out using a new module for TOUGH2 [7] called EOS7C. This simulator calculates real-gas mixture properties in the ternary system H_2O–CO_2–CH_4 and models flow and transport of supercritical CO_2, CH_4, and water in gas and aqueous phases in three-dimensional model reservoirs.

We present in Fig. 3 simulation results for the gas composition and density after 15 years of injection and production. Note that injecting CO_2 into the lower part of the reservoir while producing gas from the upper part of the reservoir exploits the large density contrast between CO_2 and CH_4 to delay CO_2 breakthrough and effectively fill the reservoir from the bottom up. To

Table 1
Properties of the three-dimensional quarter five-spot domain

Property	Value	
Quarter five spot size	800×800 m	160 acres
Reservoir thickness	50 m	160 feet
Porosity	0.30	0.30
Permeability (isotropic)	1×10^{-12} m^2	1 darcy
Residual liquid saturation	0.20	
Relative permeability		
Liquid	Immobile	
Gas	Equal to gas saturation	
Molecular diffusivity in gas and liquid	1.0×10^{-5} m^2 s^{-1}, 1.0×10^{-10} m^2 s^{-1}	
Reservoir temperature	75 °C	167 °F
Reservoir pressure at start of CSEGR	50 bars	725 psi
CO_2 injection rate (per full well)	3 kg s^{-1}	260 t/day
CH_4 production rate (per full well)	0.56 kg s^{-1}	48 t/day
Final reservoir pressure (after 15 years)	60 bars	870 psi

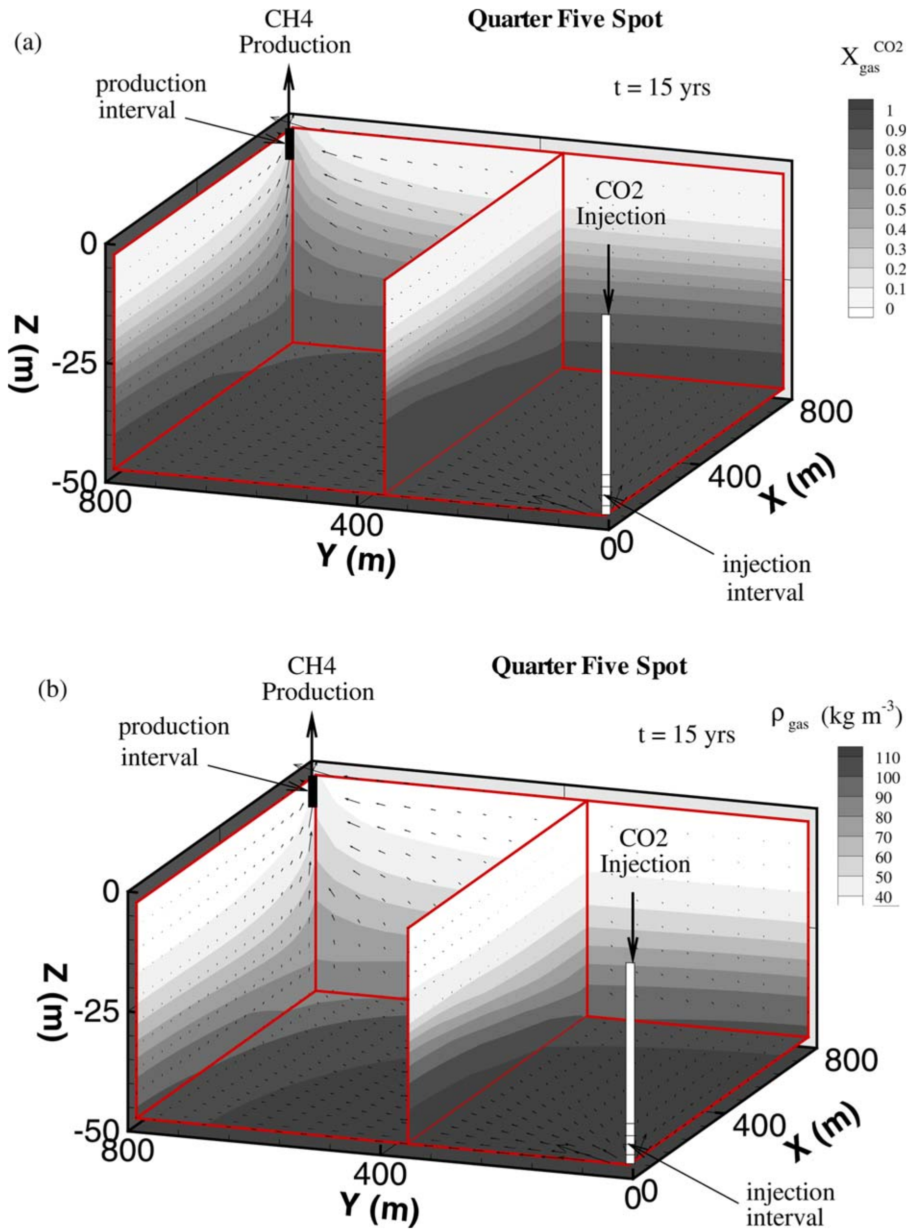

Fig. 3. (a) CO_2 mass fraction in the gas and (b) gas density after 15 years of injection into the lower part of the reservoir.

summarize the large number of process simulations we have carried out over the last few years, we can say that (1) the high density and viscosity of CO_2 favor CSEGR by limiting gas mixing, (2) that reservoir heterogeneity tends to accelerate breakthrough of CO_2 to production wells, but (3) that repressurization of the reservoir occurs faster than CO_2 breakthrough. An optimal strategy is to take advantage of the higher density of CO_2 and inject it into the lower portions of the reservoir to drive out the remaining lighter CH_4, while minimizing mixing and contamination in the upper parts of the reservoir. Our simulations suggest that CSEGR is feasible from a process perspective in that the injection of CO_2 into depleted gas reservoirs can enhance CH_4 recovery, while simultaneously sequestering large amounts of CO_2. In the following section, we analyze the economic feasibility of this particular CSEGR scenario.

3. Economic feasibility analysis

The economic feasibility of CSEGR depends on the incremental benefits of gas recovery relative to the incremental expenses of CSEGR. A key decision for evaluating CSEGR applications—as well as for CO_2-enhanced oil recovery and coalbed methane projects—is proper timing: At what stage is CO_2 injection optimal? CSEGR technology may be applied at any stage in the life of a natural gas field, from initial discovery and development all the way to depletion and field abandonment. We believe that the optimal application of CSEGR is in mature (but not abandoned) natural gas fields where production is declining. We refer to such mature reservoirs that are still in production but that are becoming depleted as "depleting" reservoirs and focus our analysis on applying CSEGR at this stage in the life of the reservoir. A depleting gas field already has in place a working infrastructure of producing wells, gas gathering, treatment, compression, and transport facilities, plus the necessary regulatory approvals. In contrast, newly discovered fields lack infrastructure and their reservoir behavior is still poorly understood, making CO_2 injection more risky. Likewise, abandoned fields face large rehabilitation costs as well as regulatory hurdles. Our economic model assumes that CSEGR is applied to a depleting gas field, such as the Rio Vista field in the Sacramento Valley, the largest onshore gas field in California [6], estimated to contain an additional 3 Tcf of recoverable gas [8].

Incremental capital costs for CSEGR include CO_2 acquisition and transport via pipeline to the field, distribution of CO_2 within the field, injection wells, monitoring systems, CH_4 compression and (eventually) CH_4/CO_2 separation facilities. A major expense today is the cost of acquiring CO_2, which may range from US$ 10/t from a relatively pure fertilizer or cement plant source up to US$ 50/t for a retrofitted power plant. We assumed that CO_2 is supplied at high purity and pressure to the pipeline terminus. We computed the maximum price that the field operator could afford to pay for CO_2 supply to break even under a 15% rate of return (pre-income taxes), under varying wellhead gas price and CO_2/CH_4 ratios. We assumed that the field operator would construct a new 50-km long pipeline and pipeline distribution network to transport CO_2 from the supply source to wells throughout the field. We assumed that existing shut-in or abandoned wells could be converted to dedicated CO_2 injection or monitoring wells at a cost of approximately one-third that of drilling new wells. Eventually, injected CO_2 mixes with CH_4 within the reservoir, requiring costly gas separation and conversion of the wellhead and flow lines to corrosion-resistant materials.

We estimated capital and operating costs for the CSEGR application based on current California gas production operations and experience at natural CO_2 production fields and EOR operations. The economic analysis is carried out with the same assumptions as the reservoir simulation presented above, with development and cost assumptions summarized in Tables 2 and 3. Standard royalty, severance, and other production taxes were subtracted from the cash flow.

Table 2
Design parameters for CSEGR application at a California depleting gas field (US$ 2002)

Parameter	Value	
Reservoir depth	1500 m	4921 feet
Reservoir type	Sandstone, high porosity and permeability	
Total field CO_2 storage capacity	3.6×10^7 t	0.7 Tcf
Total field CO_2 injection rate	6500 t/day	125 MMcfd
CO_2 injection rate (per well)	260 t/day	5.0 MMcfd
CH_4 production rate (peak per well)	48–95 t/day	2.5–5.0 MMcfd
Wellhead natural gas price	US \$ 0.11–0.18/m^3	US\$ 3.00–5.00/Mcf
CO_2 injection wells	25 wells	
CH_4 production wells	16 wells	
Monitoring wells	8 wells	
Project duration	15 years	
Nominal CO_2 content at production wells	Years 1–5: 0% Years 5–10: 5% Years 10–15: 25%	

Mcf = 1×10^3 ft^3 = 28.3 m^3, MMcf = 1×10^6 ft^3, Tcf = 1×10^{12} ft^3, t = tonne = 1×10^3 kg.

While most of the variables in the model are generalized economic variables, some depend on the physical processes of CSEGR and can be estimated from reservoir simulation results. For example, the volumetric ratio of injected CO_2 to incrementally produced CH_4 depends on processes in the reservoir. Physically, this ratio represents the efficiency of EGR in terms of the displacement of CH_4 by CO_2; the closer the ratio is to unity, the more efficient is the gas recovery process. The degree to which this ratio is greater than unity can reflect the combined effects of repressurization of the reservoir, dissolution of CO_2 into connate water, gas mixing, and reservoir geometry. Briefly, the CO_2 is denser than CH_4 and the change in density of CO_2 as pressure

Table 3
Capital costs (US$ 2002) for CSEGR application at a California depleting gas field

Cost Item	Unit Cost (×1000 US\$)	Units	Total cost (million US\$)
Wells			
CH_4 production well: new completion	390	4	1.56
CH_4 production well: workovers	40	12	0.48
CO_2 Injection well: new completion	460	5	2.30
CO_2 Injection well: converted CH_4 Well	180	20	3.60
Monitoring well: converted CH_4 Well	70	8	0.56
Total well costs			8.50
Pipelines			
CO_2 transport pipeline (8-in. diameter)	125	50 km	6.25
CO_2 field distribution lines (2-in. diameter)	30	10 km	0.30
Total CO_2 pipeline and distribution costs			6.55
Total capital costs			15.05

increases through the critical pressure of 73.8 bars is much larger than the change in density of CH_4 at typical reservoir temperatures. The result of this difference is that it takes more CO_2 to displace a given volume of CH_4 in a high-pressure reservoir. However, because deeper reservoirs tend to be at higher temperatures, the effects of higher pressure on CO_2 density are moderated. Furthermore, while repressurization and dissolution tend to make the ratio larger than unity, gas mixing decreases the ratio because the density of supercritical CO_2 decreases drastically upon mixing with small amounts of CH_4 which causes pressure increases with no additional injection whatsoever (e.g., [4]).

To capture expected variability in volume ratio, we tested the sensitivity of the result using volume ratio values of 1.5, 2.0, and 3.0 by varying the assumed incremental CH_4 production under a constant CO_2 injection rate. For reference, the volumetric ratio for the idealized case simulated above was approximately 2.0. Another physical property that can be estimated from simulation results is the gas composition, or mass fraction CH_4 in the produced gas. This property starts at unity in CSEGR, but declines as mixing occurs in the reservoir and CO_2 breaks through to the production wells. At 15 years in the scenario simulated above, the CH_4 mass fraction in the gas at the production well is approximately 0.80. For the purposes of the economic analysis presented here, we will assume that EGR is stopped (reservoir shut in) if the mass fraction of CH_4 drops below 0.5 at the production well. Carbon sequestration by CO_2 injection can continue for decades after the reservoir is shut in [1]. Following CSEGR, the CO_2-filled reservoir can be used for gas storage with CO_2 serving as a very effective cushion gas because of its large effective compressibility around its critical pressure and temperature [9].

4. Results

The economic analysis shows that CSEGR may be economically feasible if the supply cost of CO_2 is low, if CO_2/CH_4 mixing is slow so there is little CO_2 breakthrough, and if there is a significant amount of CH_4 remaining in the reservoir to be recovered. Sensitivity analysis using the CSEGR economic model shows that the most critical parameters are wellhead natural gas price and the ratio of CO_2 injected to incremental CH_4 produced. The risk of natural gas price drop may be hedged, while capital costs may be estimated with reasonable certainty. Thus, the major remaining unknown economic factors are the volumetric CO_2/CH_4 ratio and the time to breakthrough. These key factors are likely to vary from field to field, based on reservoir architecture and field operation strategies, and can be forecasted using detailed reservoir simulation. However, field testing of CSEGR is needed to demonstrate empirically its feasibility and to clarify the influence of key economic variables.

Fig. 4 shows the results of the sensitivity analysis. The base case ($CO_2/CH_4 = 1.5$ and wellhead CH_4 price = US\$ 3.00/MMBtu $\approx$ US\$ 3.00/Mcf) shows that CSEGR may be economic at CO_2 supply costs of under US\$ 8/t (US\$ 0.40/Mcf). This breakeven threshold rises to over US\$ 15/t (US\$ 0.79/Mcf) at a US\$ 5/Mcf wellhead price. These CO_2 prices are only slightly below actual current CO_2 prices from geologic sources and low-cost gas processing plants in the Permian and Rocky Mountain basins of the western USA. However, capture, separation, and compression costs from power plants are far higher, perhaps US\$ 50/t (US\$ 3.00/Mcf). Under current technology, CSEGR would require a significant subsidy for CO_2 sequestration to be economic using flue gas CO_2 sources.

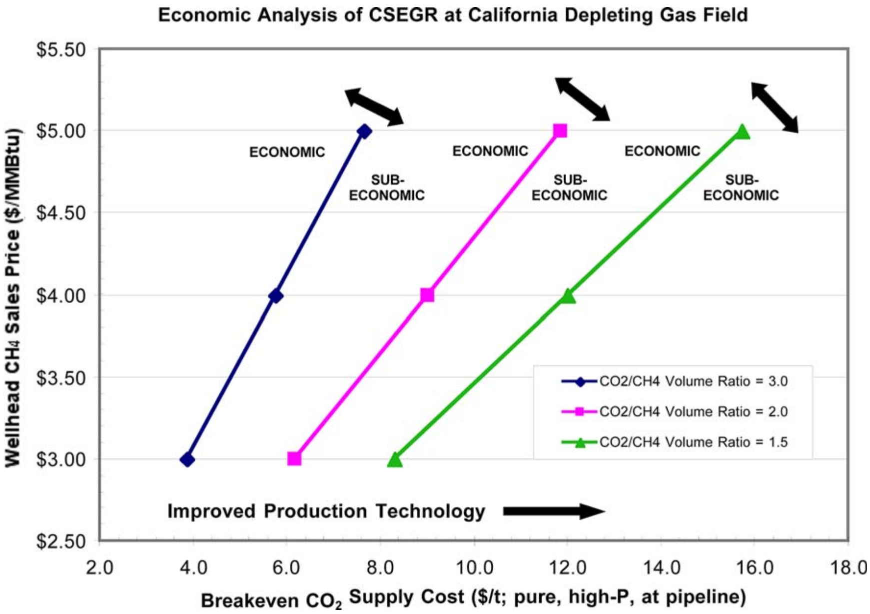

Fig. 4. Results of sensitivity analysis showing actual breakeven CO_2 supply costs (no subsidy) for various CH_4 prices.

Two other sensitivity cases were run with less optimistic assumptions, using CO_2/CH_4 ratios of 2.0 and 3.0 (Fig. 3). These scenarios represent fields with greater reservoir heterogeneity and/or less remaining CH_4 in place. Breakeven CO_2 supply costs for these less favorable reservoirs ranged from US\$ 4 to US\$ 6/t ((US\$ 0.21–0.31/Mcf) at a US\$ 3/Mcf CH_4 wellhead price. This is likely to be sub-economic even using low-cost natural CO_2 field sources, which do not exist in California. However, advances in CSEGR injection, production, and field management technologies could reduce CO_2/CH_4 ratios and improve CSEGR economics. Furthermore, if future CO_2 markets involve effective payment for carbon sequestration, CO_2 may be free to the operator or even become a potential revenue stream making CSEGR even more attractive economically.

5. Conclusions

CSEGR may be economically feasible provided the volumetric ratio of CO_2 injected to incremental CH_4 produced is less than about three, depending on CO_2 supply costs and CH_4 wellhead prices. Many uncertainties remain in the evaluation of a new recovery and sequestration process, among which are uncertain monitoring requirements and uncertain CO_2 markets. For example, possible future CO_2 markets may involve payment to operators willing to accept CO_2 and inject it into the ground for carbon sequestration. In this case, CO_2 is no longer a cost but rather a revenue and the economics of CSEGR will be considerably more favorable. In any case, CSEGR will have to be evaluated on a field-by-field basis considering reservoir properties and conditions. The analysis in this study was based on an idealized model reservoir assuming homogeneous permeability and a single gas-bearing layer. In addition, the economic model was based on simulation results of a low-pressure reservoir, i.e., highly depleted and below the critical pressure of CO_2. For these reasons, the results of our study must be considered tentative and subject to revision as more detailed reservoir simulations are carried out. Nevertheless, our results suggest that CSEGR will be feasible under certain conditions. Because both reservoir simulation and laboratory studies have also suggested that CSEGR is technically feasible, it is now time to consider seriously the development of a field pilot-study test of CSEGR.

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